CALIFORNIA ENERGY COMMISSION

STAFF FORECAST OF 2007 PEAK DEMAND

STAFF REPORT

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CALIFORNIA ENERGY COMMISSION

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Introduction and Background

This document describes staff's updated 2007 peak demand forecasts for the territories of the three investor-owned utility (IOUs), Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). The primary purpose of this updated 2007 peak forecast is to provide a reference case for the California Public Utilities Commission's (CPUC) resource adequacy process. A revised ten-year forecast for the IOUs, as well as a revised forecast for the rest of the state, will be developed as part of the 2007 *Integrated Energy Policy Report* (*Energy Report*).

The CPUC determined in their resource adequacy proceeding that the Energy Commission demand forecast, as the "state's official load forecast," should serve as the reference case in the resource adequacy load forecast review and adjustment process which is implemented by Energy Commission staff.[1] If the sum of the year-ahead forecasts submitted by load serving entities (LSEs) is more than one percent different than the Energy Commission forecast, staff adjusts the LSE forecasts to within one percent, as directed by the CPUC. These adjusted forecasts must be used in the LSE's year-ahead compliance filing with the CPUC in which they demonstrate that they have contracted in advance for ninety percent of their forecasted peak demand. For the 2006 forecasts, a small increase was necessary.

The September 2005 forecast, prepared for the 2005 *Energy Report*, is the most recent adopted Energy Commission forecast.[2] This forecast was based on actual historic energy consumption and peak demand through the year 2004. To establish a peak forecast for the 2007 resource adequacy process, staff evaluated the 2005 recorded loads and temperature data and analyzed how much that forecast should be revised.

Staff's initial results were presented at an Electricity Committee workshop on June 5, 2006. Representatives of SCE and SDG&E generally concurred with staff's proposed forecast. PG&E raised concerns about the magnitude of the increase based solely on an estimate of the weather adjusted peak. The Committee directed staff to work with PG&E to resolve the discrepancy between forecasts. This report incorporates the resulting revised PG&E forecast. The forecasts for the SDG&E and SCE areas are unchanged.

Summary of Results

To develop the 2007 peak demand forecast, staff first estimated the relationship between temperature and daily summer peak demand for each service area. This estimated equation was applied to the historic average of annual maximum temperatures to derive an estimate of weather-adjusted demand for 2005. Finally, the growth rate from the September 2005 demand forecast was used to produce a revised annual peak forecast for 2007.

Although SCE uses a different set of weather stations and both SDG&E and SCE use somewhat different methodologies, those utilities generally concurred with staff's results. For PG&E, however, staff found that the weather stations used by PG&E produced a much different estimate of the 2005 weather-adjusted peak than the weather stations used by Energy Commission staff. To account for the uncertainty around this estimate, staff used the average of the estimated peak using the two different sets of weather stations.

Table 1 shows the results of this analysis. The 2005 column shows the estimates of the weather adjusted peaks compared to the forecast. The 2007 column compares the September 2005 forecast with the proposed revised forecast. For all three areas, the weather adjusted peak is significantly higher than originally projected. As a result, the revised 2007 forecast for SCE is more than four percent higher than the September 2005 forecast of 2007, while the SDG&E forecast increases by 1.8 percent. The PG&E forecast is 2.8 percent higher than the September 2005 forecast.

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Table 1: Revised versus September 2005 Peak Demand Forecast Megawatts (MW)

		2005	2007	Annual Growth Rate
PG&E Service Area	**Sept. 2005 *Energy Report* Forecast**	18,311	18,914	1.6%
	May Draft Forecast	19,272	19,905	1.6%
	Final	18,820	19,440	1.6%
	Change from Sept. 2005	509	526	
SCE Planning Area	**Sept. 2005 *Energy Report* Forecast**	21,510	22,163	1.5%
	Revised Forecast	22,442	23,124	1.5%
	Change	932	960	
SDG&E	**Sept. 2005 *Energy Report* Forecast**	4,231	4,371	1.6%
	Revised Forecast	4,307	4,450	1.6%
	Change	76	79	

The final forecast of 2007 will be applied to hourly forecast load shapes from the IOUs to develop a monthly peak forecast for each service area. For SCE, whose Federal Energy Regulatory Commission (FERC) Form 714 hourly loads include non-CPUC jurisdictional LSEs, staff will use historic loads for individual LSEs (from both FERC Form 714 and California Independent System Operator (CA ISO) hourly settlement data) to disaggregate the planning area peak forecast into SCE service area and publicly owned utility components.

The remainder of this document describes the methodology and data used for each utility forecast, followed by a discussion of possible sources of forecast error.

General Weather Normalization Methodology

Staff used preliminary 2005 FERC Form 714 hourly load data and utility planning area daily temperatures to estimate the relationship between the summer weekday afternoon (1 PM-6 PM) peak and temperatures. Summer is defined to be the period from June 15 to September 15 for this analysis. The temperature variable for each utility is a weighted average of temperatures from a set of weather stations that are representative of the climate in that utility region (Table 2). The weights are based on the estimated number of residential air conditioning units in each of the utility forecast zones as assumed in the Energy Commission residential demand forecast model. Since the May 2006 draft forecast, staff has modified the weights for PG&E weather stations to more accurately account for the distribution of air conditioners.

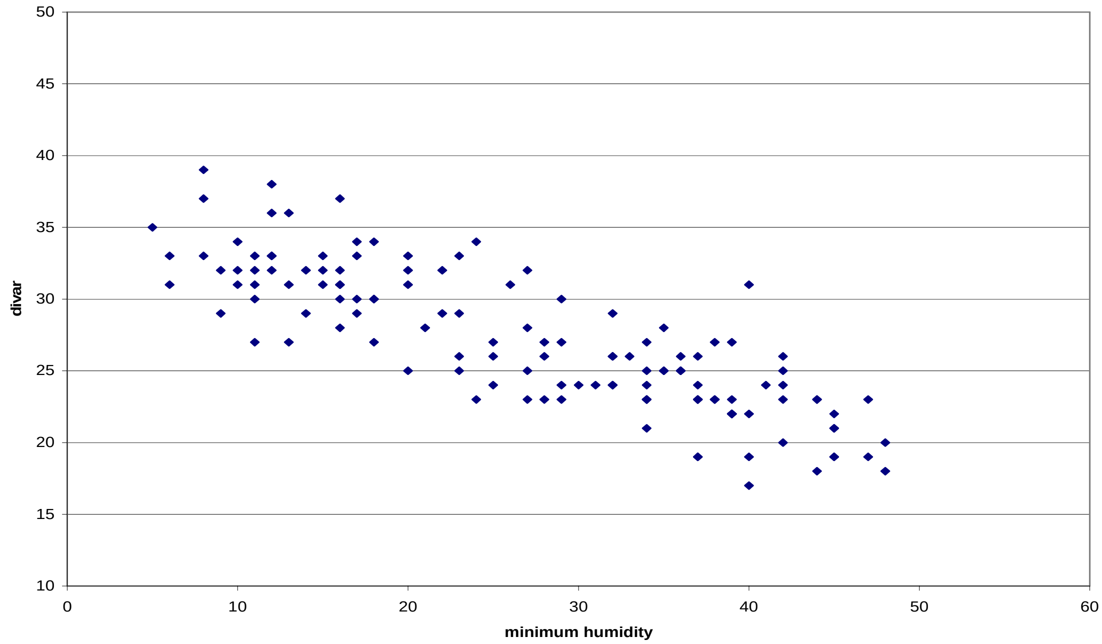
Table 2: Planning Area Weather Weighting Factors

Utility	Station/Weight				
PG&E	**Ukiah**	**Sacramento**	**Fresno**	**San Jose**	**San Francisco**
May Weights	0.072	0.144	0.422	0.325	0.037
New Weights	0.067	0.169	0.413	0.282	0.069
SCE	**Fresno**	**Long Beach**	**Burbank**	**Riverside**	
	0.062	0.324	0.243	0.371	
SDG&E	**Lindbergh Field**	**Mirimar**	**El Cajon**		
	0.333	0.333	0.333		

Two separate weather variables were calculated for this analysis. The first is a weighted average of maximum temperatures on three days (*max631*). The weighting consists of 60 percent of the current day's maximum temperature, 30 percent of the previous day's maximum and 10 percent of the second previous day's maximum. The lag is used to account for heat build-up over a three day period. The "1-in-2" or normal peak temperature is the median annual maximum temperature, over the 1950-2005 period, for PG&E and SCE. The time period used for the SDG&E planning area was limited to 1979-2005 because daily weather data is not continuously available for El Cajon prior to 1979.

The daily temperature spread, or diurnal variation (*divar*) is the second temperature variable. This variable is the daily maximum temperature minus the daily minimum temperature. It serves as a proxy measure of daily humidity. The assumption is that the lower the daily temperature spread for a given temperature, the higher the daily humidity (i.e. a day with a maximum temperature of 95 degrees Fahrenheit (deg F) and a minimum of 75 deg F is likely to be more humid than a day with a maximum temperature of 95 deg F and a minimum temperature of 65 deg F). This proxy is used because there is little historic information available for long time periods on humidity for most weather stations, while daily maximum and minimum temperatures are readily available. Figure 1 shows the relationship between daily diurnal variation and minimum humidity for Burbank on days which the maximum temperature was 80 deg F or above.

Figure 1: Daily Minimum Humidity and Diurnal Variation
(Burbank 2005 daily maximum temperature 80 deg F or above)



This variable was developed because of abnormally high humidity from the remnants of hurricane Emily, which dissipated westward along the U.S.-Mexico border and into southern California and drove, in part, the 2005 southern California peak. Emily caused increased humidity relative to normal weather patterns, primarily in the SCE service area with a minor impact in the SDG&E service area. The daily diurnal variation is not lagged because it is intended to provide a measurement of the actual daily humidity which impacts the physical need for air conditioning compressors to take water vapor out of the air.

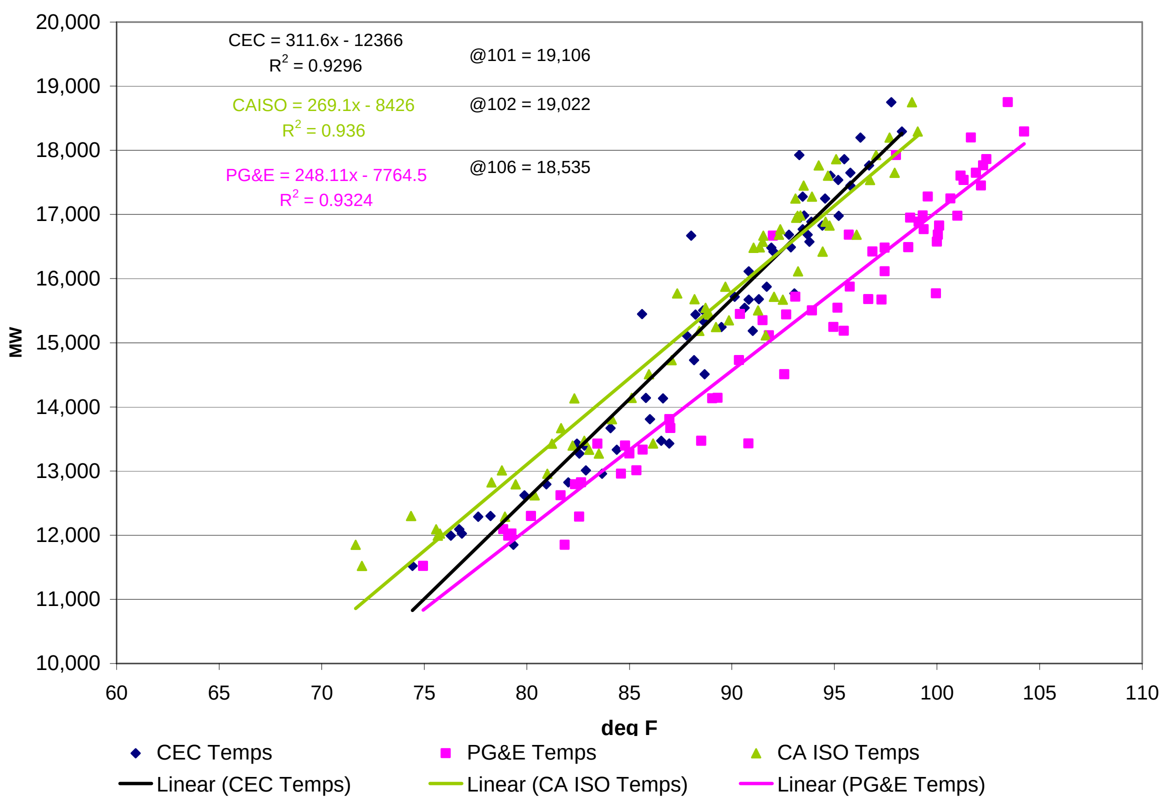
PG&E Service Area Results

Staff initially made two changes to its draft forecast for PG&E. First, the weather stations were reweighted to more accurately reflect the current distribution of residential air conditioning units. Second, reductions in load from demand response or interruptible programs called during the summer of 2005 were added to recorded load. These changes produced a slightly lower estimate of the 1-2 peak (19,106 MW versus 19,272 MW in the May report.)

Estimates of weather-adjusted demand can sometimes vary significantly depending on the data and methods used. Staff investigated a number of statistical models and data sources and found the key reason for the difference between PG&E and staff forecasts is the weather stations used. Figure 2 presents the temperature-load relationships for the summer weekday period (June 15th through September 15th)estimated using three different sets of weather stations: the stations used by Energy Commission staff, the eleven stations used by the CA ISO, and the two stations used by PG&E. Also shown is the estimated peak at the 1-in-2 temperature for each set of weather stations. The weather normalized peaks assume that the temperature-load relationship estimated from the below average temperatures experienced in the summer of 2005 is also valid at 1-in-2 temperatures.

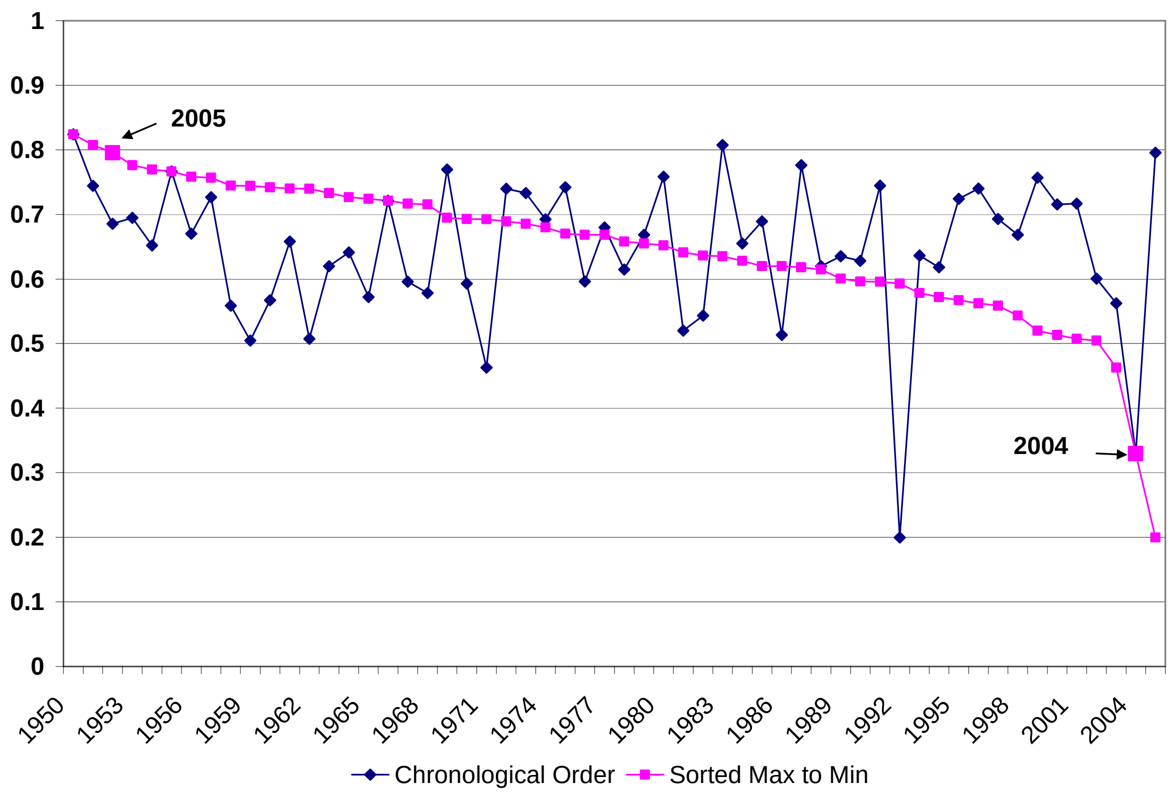
Each set of weather stations produces a different temperature-load response relationship. The weather stations used by the CA ISO produce results similar to the staff estimate, while the PG&E station estimate indicates a lower response to increasing temperatures.

Figure 2: PG&E 2005 Summer Weekday Peaks vs. Temperature



While maximum temperatures in 2005 were below average, the pattern of temperatures was unusual in that Fresno and San Jose experienced high temperatures at the same time. Typically temperatures between Fresno and San Jose have a correlation of about 65%, but in 2005 the correlation was 80%, the second highest in the last fifty years. Figure 3 shows the large swing in correlation from 2004, when the two temperature series had very low correlation, to 2005. The weather stations used by PG&E, Fresno and Livermore, exhibit a similar pattern, but the change from 2004 to 2005 is of a smaller magnitude. This illustrates the difficulty of analyzing load growth in a region with the diverse climates of PG&E. The same weighted average temperature can be created by very different weather patterns.

Figure 3: Correlation between Fresno and San Jose Temperatures



Staff will continue to investigate the effects of this temperature coincidence on loads and our estimates of load growth. More disaggregate load data could shed light on the nature of the underlying load growth.

Meanwhile, for the 2007 peak forecast to be used for the year-ahead resource adequacy submittals, staff used the Energy Commission and PG&E estimates shown in Figure 2 to construct a forecast range. The average of the two estimates produces a forecast of 19,440 MW for 2007. Staff will reevaluate this forecast based on loads observed during the summer of 2006 and as part of our more comprehensive forecast revision for the 2007 ***Energy Report***.

SCE Planning Area Results

A combination of high temperatures and abnormally high humidity caused the 2005 peak demand in the SCE planning area. Staff investigated two models for weather normalization. The first model considered lagged temperature only and the second considered both lagged temperature and daily diurnal variation as a proxy for humidity as described above. Figure 4 presents the predicted and actual results of both models. Adding diurnal variation as an explanatory variable increased the R^2 from 0.87 to 0.91.[3]

Figure 4: Predicted SCE Weekday Peaks Using Temperature and Diurnal Variation

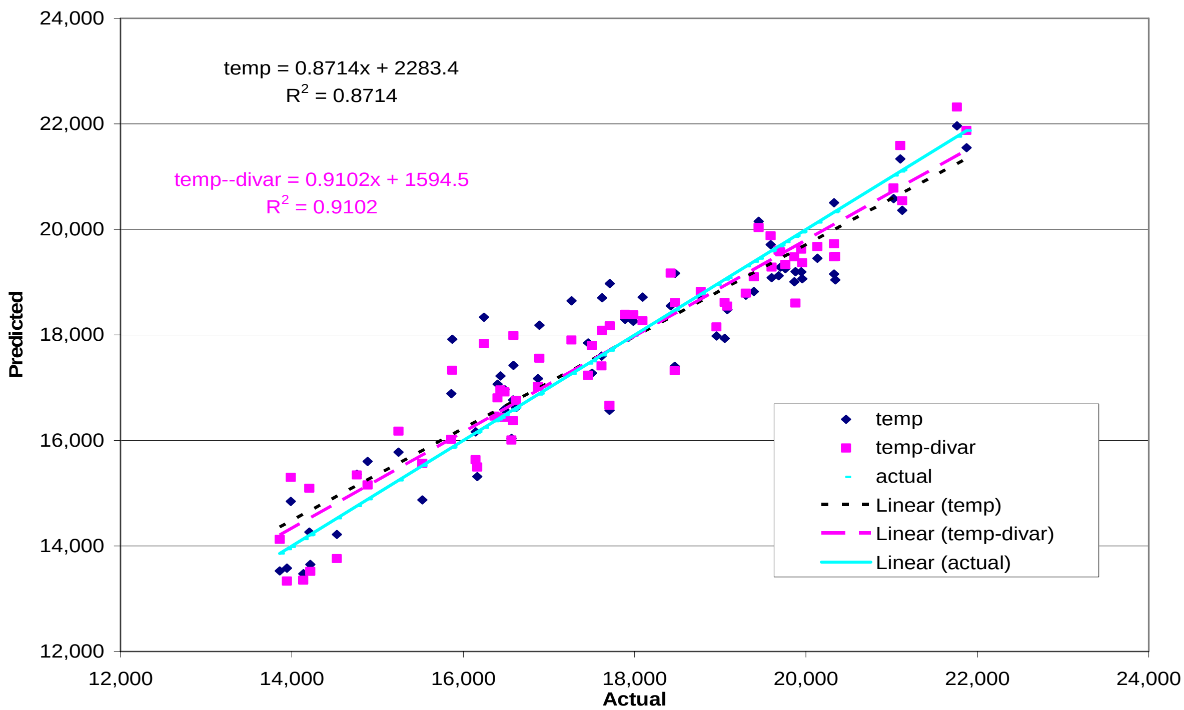
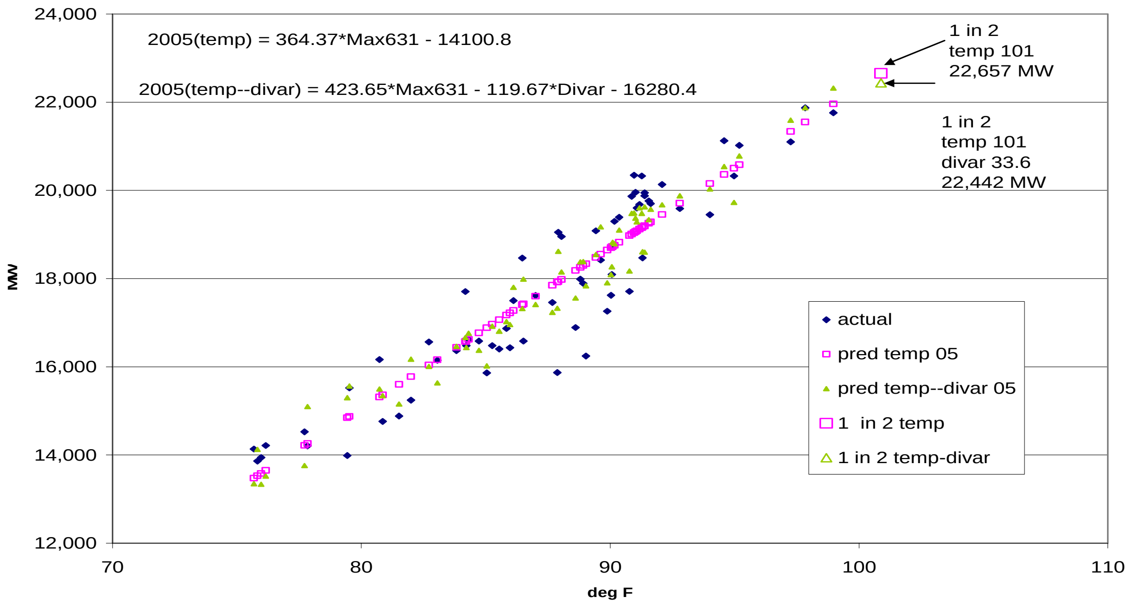


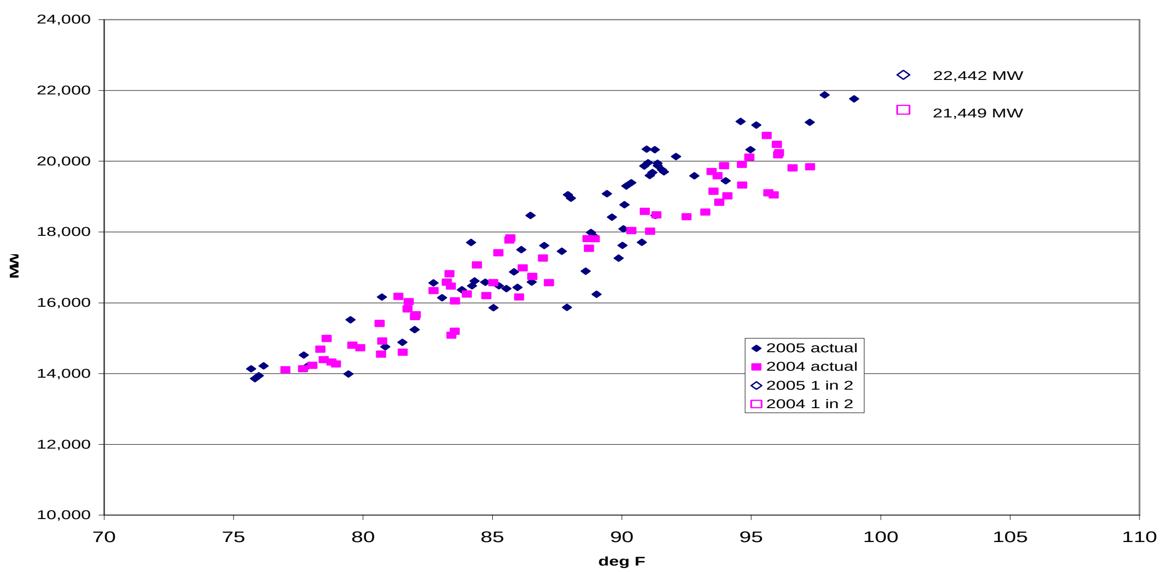
Figure 5 presents 2005 predictions using both temperature (*max631)* and temperature plus the diurnal variation variable (*divar*) as a proxy for humidity. Including *divar* reduces the 2005 weather normalized peak approximately 215 MW over temperature alone. The “normal” diurnal variation (33.55) is defined as the average diurnal variation that occurred at the median SCE peak temperature of 101 deg F over the 1950-2005 period.

Figure 5: Model Results of SCE 2005 Summer Weekday Peak And Weather Variables



Summer weekday peaks for 2004 and 2005 along with the weather normalized peak values for each year are compared (Figure 6). The *divar* variable was used in the weather normalization for both years because it proved to be a significant explanatory variable of weekday peak loads for each year.

Figure 6: SCE 2004 – 2005 Summer Weekday Temperature-Peak Comparison



SDG&E Planning Area Results

The SDG&E planning area analysis used both lagged maximum temperature and daily diurnal variation. Staff also used a combination of Lindberg field, Miramar Naval Air station and El Cajon weather stations to represent the SDG&E planning area, rather than only Lindberg field as has been done in the past. Because staff has no reliable weather information for El Cajon prior to 1979, the time period for historic analysis was limited to 1979-2005 to use data from the three weather stations. The weather variables were calculated as an average of the three stations. The regression fit was improved by using both *max631* and *divar* (R^2=0.91) compared to using only *max631* (R^2=0.88) (Figure 7)**.**

Figure 7: Predicted SDG&E Weekday Peaks Using Temperature and Diurnal Variation

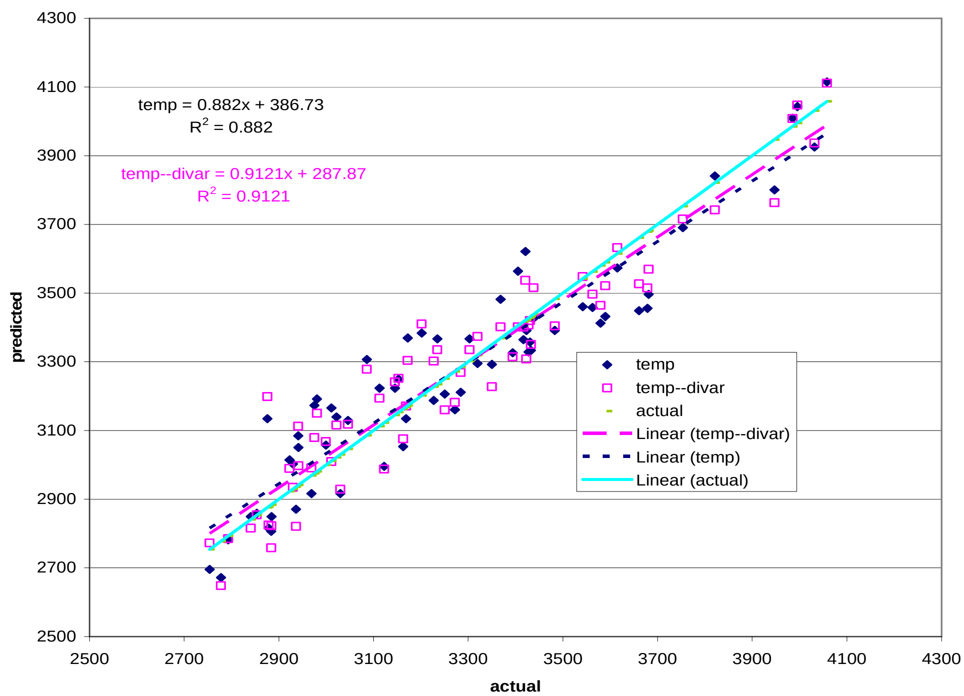
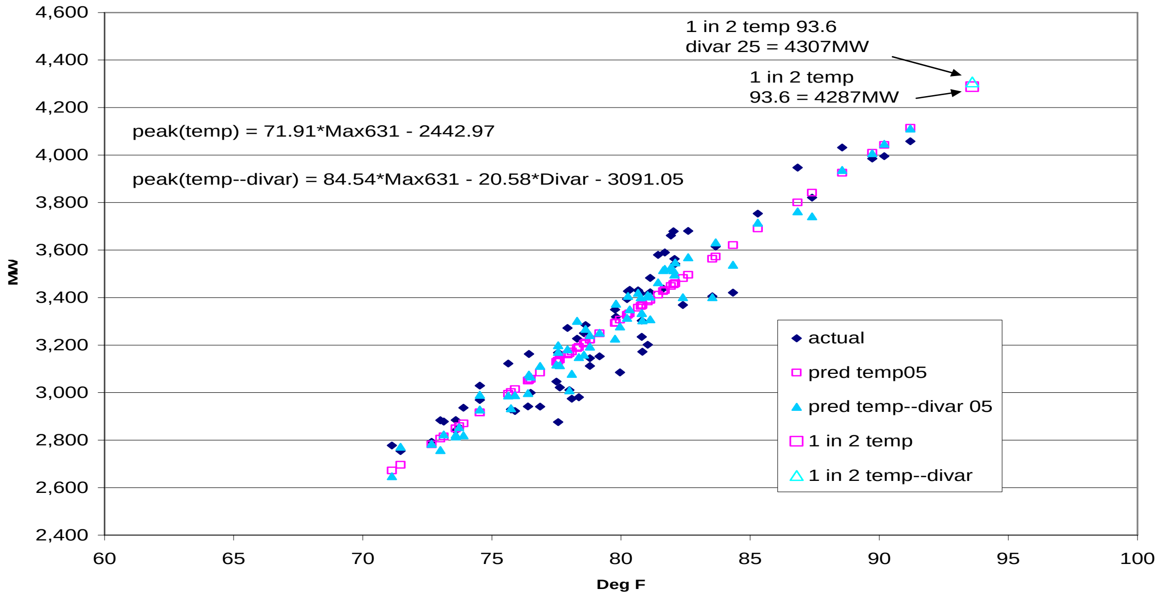


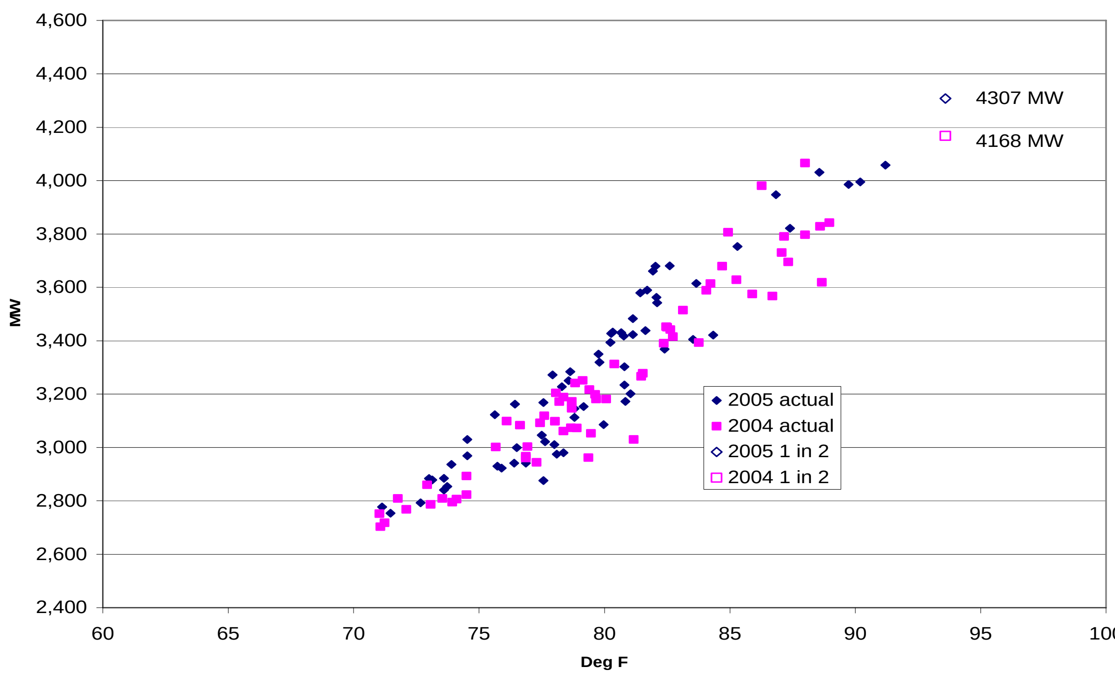
Figure 8 presents the 2005 predictions using both temperature and temperature in combination with the diurnal variation variable. Including the diurnal variation variable in the SDG&E planning area increases the estimates of the weather-adjusted peak approximately 20 MW.

Figure 8: Model Results of SDG&E 2005 Summer Weekday Peak And Weather Variables



Summer weekday peaks and weather normalized values for both 2004 and 2005 are compared in Figure 9.

Figure 9: SDG&E 2004 – 2005 Summer Weekday Temperature-Peak Comparison



Sources of Forecast Error

Staff's initial assessment is that the forecast error was caused at least in part by model assumptions that underestimate the percentage of homes with central air conditioning. Analysis of the 2004 Residential Appliance Saturation Survey (RASS) data is yielding data on the percentage of homes with central air conditioning that, for many climate zones, are significantly higher than those assumed in the September 2005 forecast. The September 2005 forecast used assumptions based on much older survey data; updated saturations from the 2004 RASS were not yet available. The new RASS results suggest that many more existing homes have been retrofit with central air conditioning than assumed by the residential forecast model, particularly in more temperate climates such as the San Jose and Long Beach zones. Underestimating the number of air conditioning units in these areas is likely to have a disproportionate impact on peak demand compared to annual energy use because those units may be used only on the few hot days per year. A more complete analysis of the cause of the forecast error will be done as part of the 2007 *Energy Report* forecast.

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[1] Rulemaking 04-04-003, Decision 05-10-042, October 27, 2005, http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/50731.htm

[2] California Energy Demand 2006-2016 - Staff Energy Demand Forecast - Revised September 2005 - Staff FINAL Report. Publication # CEC-400-2005-034-SF-ED2. , http://www.energy.ca.gov/2005publications/CEC-400-2005-034/CEC-400-2005-034-SF-ED2.PDF

[3] R^2, the coefficient of determination, is a statistical measure of the proportion of variation in the dependent variable (peak demand) which is explained by variation in the independent variables (temperature data).